**INDIANAPOLIS POWER & LIGHT COMPANY**

**Advanced Notice of Proposed Rulemaking on Distributed Resources**

**a) Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on the customer class?**

**Answer:** Distributed generation (DG) broadly defined "is any small-scale power generation technology that provides electric power at a site closer to customers than central station generation" according to the Distributed Power Coalition of America (DPCA). This would include turbine and internal combustion generators, microturbines, photovoltaics (PV), wind turbines and fuel cells that can be owned by utilities, customers or third parties.

Self-generation by utility customers for emergency back-up and economic purposes is considered to be distributed generation. Such resources may or may not be interconnected to the utility grid. A major engineering issue concerning distributed generation is the interconnection standards for physical connection of the DG resource to the utility grid. The IEEE (Institute of Electrical and Electronics Engineers) is developing appropriate interconnection standards that will provide a specification for the installation and operation of distributed systems and increases their safety.

Engineering characteristics and size are irrelevant to the broad definition of distributed generation. Any resource that provides an effective solution to a particular need – such as back-up power, enhanced system reliability, power quality, substation and distribution circuit construction deferral – can be considered as distributed generation.

While the definition of distributed generation should not change because of generation size or customer type, an important distinction must be made between, for example, residential photovoltaic systems and large industrial power facilities. Given the way distributed generation projects should be evaluated and approved, it might be better if standard procedures are developed for small residential distributed generation projects such as solar photovoltaic systems.

**b) Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?**

**Answer:** Net metering is easily understandable for residential customers with renewable energy generation and encourages customer participation in such programs; however, net metering is not equitable for larger distributed generation applications if the customer credit is equal to the fully bundled retail rate for electricity. The bundled retail rate includes costs for distribution, transmission, customer service functions, and back-up provisions provided by the electric utility. Using an average rate for net metering would allow larger dispatchable customer-owned generation to game the system, as discussed more fully hereinafter.

**c) What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?**

**Answer:**

**Small Customers**

With regard to small customers, the current IPL tariff provides one possible near term approach to address this matter. As mentioned in the IURC White Paper, IPL currently provides a net metering tariff for residential customers and schools for PV applications. The customer's meter "spins" both ways and the customer gets a reduction on its bill at the full tariff rate for any energy it produces. While both theoretical and practical reasons exist to apply this form of net metering to small PV projects, the approach of generally providing a credit of the full bundled tariff credit is not fair or reasonable. As a practical matter, both the time of availability of photovoltaic systems and the fact that the amount of revenue reduction will not be material for the next several years, makes the net metering approach in this narrow application appropriate. This low level of participation is primarily due to the poor economics of PV or other small DG resources.

Additionally, this approach is fairly easy to administer. In order to mitigate the risk to the utility and other customers, the availability of the tariff could be capped to a set number of customers or a maximum of installed megawatts of capacity. If demand begins to approach the number of customers set aside, then a more detailed proceeding could be undertaken to determine a more fair and equitable approach to net metered customers. Another advantage of this approach is that it provides the utilities and the customers with some information on how these devices operate. It will also provide an impetus to the marketplace by encouraging customers to invest in these technologies.

**Large Applications**

With regard to tariff provisions for larger applications of DG technologies, IPL again points to our Tariff Riders that provide for customer billing credits or purchase of the output from customer owned generation.

Please also see our responses to questions d and e below.

**d) How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?**

**Answer:** IPL has been a proponent of utilizing customer owned generation during peak times to benefit all IPL customers. IPL's Standard Contract Riders No. 15 and 16 provide customers a capacity and energy credit to operate their distributed generation equipment to help reduce wholesale spot energy purchases during times of high demand. In addition, IPL's Rider No. 9 provides residential customers and schools with a net metering alternative for use with solar PV systems. However, some advocates have proposed a form of net metering where the customer credit per kWh is equal to the fully bundled retail rate for all forms of distributed generation. Included within the bundled retail rate (which such schemes would consider as a "credit") is not only compensation for the distribution, transmission and customer services functions provided by the electric utility, but also compensation for the "demand" or back-up component associated with any obligation to serve the customer's full need for energy whenever the distributed resource was not operating. Moreover, under such schemes the customer could produce excess electricity when overall electricity demand is low, and thus energy prices are low, and essentially take very expensive on peak energy free. Thus, a retail customer could produce enough electricity and equivalent rate net metering credits to pay a zero electric bill, and yet take full requirements service on the hottest days of the year from the electric utility while paying nothing to receive distribution, transmission and customer services. In the context of industrial or commercial customers, such schemes would be both disastrous and confiscatory.

The question regarding the determination of the fixed amount of cost per customer should be considered within the context of the interruptiblity of the service. Customers who want to maintain full control over their abilities to receive or take service should be billed at current retail rates. However, if customers are willing to provide some optionality to benefit themselves, other customers, and the utility, incentives based upon forward wholesale energy prices could be devised to benefit all constituents. In fact, IPL Riders 15 & 16 provide customers such incentives and benefits.

*When any customer installs a system to serve his own load, the most likely time that customer would be feeding power back to the utility, is when his overall energy demand is low. Unfortunately, this is also likely when the utility and its other customers least benefit from it. Since there would be little "capacity" value at those times, an argument can be made that the customer should only receive an "energy" credit.*

In conclusion, while not precisely reflecting the value of 'net metered' power, using existing tariff rates is the cleanest, simplest, and <u>for now</u>, most appropriate rate to employ for <u>select</u> distributed generation. For this reason, IPL limits this service to PVs, which better coincides with IPL's resource needs. If a customer can generate more than his own energy requirements, it provides a means to reduce his/her energy bill from the host utility.

Because IPL still has an obligation to serve all its customers and must provide the appropriate distribution and metering equipment as well as customer service, billing, outage, back-up, and other services to all its customers, there is no fixed cost savings for a customer that is a net seller to the utility. This cannot be ignored when evaluating large distributed generation projects or those lacking the special characteristics of PVs.

**e) How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for services to customers that operate DG equipment using a net meter?**

**Answer:** The recovery of the fixed and variable costs to operate distributed resources must be analyzed and justified against the bundled retail rates serving that specific customer. The existing bundled rates include the recovery of back-up service, transmission, distribution and customer service expenses. Any subsidies for the installation of non-economic distributed resources would burden all other retail customers and impair conservation and non-generation based load management efforts. Given IPL's low rates and the current cost for distributed resources, the economic justification to install customer premise distributed resources is extremely difficult on a pure stand-alone basis. At a minimum, distributed resource tariffs, for large industrial power facilities, should only be designed to provide service at full retail rates less the utility's cost of fuel or purchased power costs.

**f) How can stranded costs be identified and measured?**

**Answer:** Stranded cost can loosely be defined as a situation which occurs when any technological, circumstantial or legal change renders utility plant, property and equipment worth less than accounting book value. This may include, but is not limited to, change which renders utility plant, property and equipment no longer used and useful. In jurisdictions adhering to the original cost prudent investment theory of utility price control, the case has been sustained for an obligation on the part of consumers to assure the recovery of accounting book value to the utility in a situation of stranded cost. This is called "stranded cost recovery" and can be achieved in many ways.

In jurisdictions which control prices based on the actual current fair value of utility property, stranded cost recovery is irrelevant. In such jurisdictions, like Indiana under IC 8-1-2-6, the utility is entitled to the gain, and risks the loss, from changes in the value of its plant, property and equipment. Accordingly, with narrow exceptions, the fact that technological, circumstantial or legal change drives the actual current value of utility plant significantly above or below net book value is to be expected, and is an incident of the utility's ownership of that property. As long as the regulatory authority has actually recognized increases in property value, and approves rates on that basis, it is free to recognize declines in the value, and reduce the utility's revenue requirements accordingly.

**g) What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?**

**Answer:** While the above discussion suggests that stranded costs from distributed generation are of little concern under the Indiana regulatory scheme, it is a far more practical issue controls the answer to the Commission's inquiry. While the theoretical possibility exists that proliferating distributed generation will "strand" existing utility generation, transmission, distribution or customer service plant and equipment, as a practical matter, substantial stranded costs are highly unlikely for the foreseeable future. This is true for three basic reasons. First, absent profound technological or legal changes, distributed generation will be a cost competitive alternative only in very limited circumstances and, as a practical matter, the capacity to produce and install distributed generation to replace or render irrelevant, existing generation, transmission and distribution does not exist. Accordingly, distributed generation will likely help meet incremental and special needs as it is increasingly integrated into the national power supply. This is especially true in areas such as IPL's where consumer power prices are very low.

Second, for the foreseeable future most distributed generation will actually require approximately the same utility plant and equipment to provide back-up and interconnection services to the distributed generation customer, suggesting an actual increase, rather than a decrease, in the value of that property. Third, as discussed elsewhere, the modern interconnected transmission and distribution networks can rarely be properly allocated to one, or even a few customers. Therefore, the use of distributed generation, or even independent self-generation (disconnected from the grid) by one customer would not render the plant or equipment useless, since it would continue providing service to remaining customers. The likelihood of significant decreases in value or cost shifting which could occur in such circumstance is slight unless regulatory policy or legal changes create extreme subsidies for distributed generation. For example, if a significant explicit or implicit tax is placed on utility delivered power, and is not applicable to distributed generation resources, then uneconomical distributed generation would proliferate. In such circumstances, significant decline in utility property value or cost shifting to other customers could occur.

**h) What rate design alternatives would reduce the potential for any stranded costs?**

**Answer:** Under Indiana's fair value standards, increases or decreases in utility property values as a result of technological changes like distributed generation are to be expected and are the responsibility of utility management to manage. If a utility recognizes the inherent value in distributed generation to minimize incremental generation, transmission and distribution costs while providing enhanced value to customers, distributed generation can create increased value, not stranded costs. Alternatively, if poor decisions on distributed generation are made, (or forced by policy makers), such as allowing net metering at average price for large distributed generation resources producing only unneeded or off-peak power, the distributed generation will reduce the value of utility property and cause increased costs for all other consumers.

**i) Should standby rates for backup power be used, and if so under what criteria?**

**Answer:** If a customer can generate electricity cheaper, cleaner, more reliably and believes it in its best interest, then it should be able to do so, and have standby service available from the host utility. In such circumstances, having Standby rates for back-up power to customers with their own DG seems appropriate.

The criteria generally would be that existing customers are not harmed in any way. That is, existing customers' costs do not rise, and the self-generating entity does not do anything to adversely effect the reliability of the distribution grid. An appropriate rate would be full tariff rates less fuel or purchased power.

Although the cost to serve customers varies over the distribution system, a utility does not differentiate among its current customers. An argument can be made, in an effort to optimize the system that we encourage growth in part of our service territory, and conservation in another part. For example, we could promote cheaper connections for downtown apartments, and higher costs for out-of the way homes. The difficulties are perceptions of fairness, complexity of the task, and the burdensome nature of this type of pricing activity. For these reasons, we cannot see that distributed generation offers any more compelling a reason to undertake this activity than already exists.

**j) What different kinds of standby services do customers with DG require and can the utility reasonably supply?**

**Answer:** Utilities should not be burdened with offering different types of standby service. Given the difficulty in managing these types of services, if a customer wants unique or standby service above what is generally available, it should build the appropriate resources to self supply.

**k) In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.**

**Answer:** Distribution system costs are not easily identified (defined) for a specific customer. Customers share the costs of the entire system. This sharing includes not only the large distribution feeders and substations that directly serve them, but the redundancies built in to the system that add reliability (customers can be reliably served along various distribution paths). Since these costs are shared, one customer leaving the system without paying his share places additional costs on those who remain.

In addition, the distribution system developed over many years in response to customer growth and needs. It is not a "one-time" optimized system designed for the current size and location of existing customers, but is optimized to be adaptive to those changing needs. Such a system is even more difficult to apportion between individual customers.

**l) Are there areas in Indiana with distribution constraints?**

**Answer:** Not that we are aware of. Certainly geological constraints which would inherently cause a differentiated distribution situation like oceans, mountains, etc, are not significant in Indiana (except for Lake Michigan to the North).

**m) Should utilities be required to file a location-specific set of T&D costs?**

**Answer:** No. As stated in (k), the distribution system with its "shared" and "redundant" assets and costs, is not amenable to being broken up for the purposes of identifying customer specific distribution charges or in sending a customer specific economic signal. Any such scheme would need to be market based – and even at that – would be somewhat arbitrary. These rates could not be guaranteed to exist from one year to the next – as conditions change in the service territory.

**n) What constitutes an economically efficient buy-back rate?**

**Answer:** An economically efficient buy-back rate would obtain resources for the utility and its customers at a price roughly equivalent to or less than the cost in the market and the administrative and other costs to manage that program. In that regard IPL (rider 16) looked at long term contracts that were priced very near the marginal cost of an avoided CT. With the advent of a wholesale power market, we were able to offer a rate (rider 15) that was related to the price of avoided power purchases. Since we had some high power prices during the summers of 1998 and 1999, it became administratively attractive to even include smaller customer load and generation from 1MW for rider 16, to 0.25 MW for rider 15. The payments are based similar to the wholesale power market call options – with a premium paid for the right to call on that customer/resource at a specific strike price – that is somewhat above their cost to operate.

If a customer has power to sell back to the utility when the utility does not desire it, and can produce it for 1 to 2 cents per kWh – then that is all it is worth. This is reflected in IPL's CGS filing. Utilities (by their inherent nature) produce energy very efficiently most hours of the year. In the specific situation when a distributed resource would be helpful to such a system, IPL has designed market-based incentives to take advantage of that situation for all of its customers.

**o) What information should be included in a utility standard application form for distributed generation?**

**Answer:** A suggested standard application form for medium and large scale distributed generation projects is given in Attachment I. The primary purpose of that form is to address the interconnection, system protection, and safety aspects of proposed DG systems.

A standard application form for financial and rate concerns of distributed generation (DG) may not be the best approach for evaluating and implementing DG programs. The nature of DG is such that individual projects should be carefully analyzed. Meetings between the principal parties should be used to explore all project options. The spirit of a "win/win" situation should be exercised between utilities, customers and project developers.

For small, single purpose DG projects such as residential solar PV applications (up to 10 KW of capacity), a separate standard application form might be appropriate to reduce time and effort of installation activities. For example, IPL's Standard Contract Rider No. 9, Net Metering for Customers With Solar Photovoltaic Systems, specifies that PV systems should be designed in accordance with IEEE Std 929 and UL 1741. That contact rider also outlines that net meter billing will be at full retail rates.

NEMA (National Electrical Manufacturers Association) has published a document, "Guide to Preparing a Design Proposal for Paralleling Customer Generation with an Electric Utility". This document would provide a useful basis for the utility review.

**p) What costs are incurred by a utility to review a DG project?**

**Answer:** The primary costs that a utility incurs in evaluating distributed generation projects are labor related. Siting constraints, project economics, substation and line loads, equipment reliability and back-up requirements are some of the parameters that must be addressed when evaluating a project. Such an analysis can involve many engineering hours and therefore be quite costly.

**q) Do these costs vary for different DG project proposals?**

**Answer:** The costs for evaluating DG projects vary widely because the engineering time required for different project types significantly vary. Large, complex projects can require input from several different individuals with differing areas of expertise – power quality, generation technology and fuel constraints, for example.

Small, single purpose projects such as residential PV applications are fairly straight forward, and those projects have a relatively small amount of engineering, metering and inspection hours involved in project evaluation and implementation.

r) **How long should it take to evaluate a project?**

**Answer:** Depending upon the size and complexity of a distributed generation project, evaluation could take from two weeks to six months calendar time. Calendar time is the time from when a project evaluation is made until the date that the analysis is finished. The actual engineering hours would most likely be considerably less than calendar time because of unavoidable delays and project "dead time."

s) **What are the criteria a utility should use to evaluate a DG project?**

**Answer:** There are two types of projects that a utility will need to evaluate: (1) projects where a utility is purchasing the generating or load reduction equipment, and (2) projects where a customer or third party developer is making the major capital investment. With utility projects, the utility should use its standard methods of measuring the value of any project. Customers or third party developers should, of course, be free to apply their own chosen methods of evaluation. Ideally a DG project can be designed so that both the utility and the customer can benefit financially – a "win/win" situation.

INDS01 491400v1

# Indianapolis Power & Light Company
# Interconnect Protection of Distributed Resources

The interconnection of distributed resources (DR) with the electrical system at Indianapolis Power & Light Company (IPL) requires that sufficient data be provided to IPL for review. The objectives of this review are:

- ♦ Minimize hazards to IPL personnel and the public.
- ♦ Minimize the probability of damage to utility and other customer equipment.
- ♦ Not adversely affect the quality of service to other customers.
- ♦ Not assume responsibility for protection of the customer's generators or electrical equipment.

The following list of questions is intended to cover the majority of topics to complete the review. Not all questions pertain to the installation being considered.

## General

1. What is the address of the proposed location?

## Generator Data

1. What are the ratings of the generator proposed for the interconnection, including KVA, voltage, and short circuit contribution?
2. Is the generator an induction, synchronous or inverter/converter type machine?

## Point of Disconnect

1. What is the point of disconnect between the utility and customer? A disconnect device must be identified that is visible, accessible and can be held open for safety purposes, if needed.

## Customer Electric System Data

1. What is the primary voltage at the customer installation?
2. Provide a single-line diagram of the customer installation including the interconnection and DR equipment. This diagram should represent sufficient detail to plan and evaluate the electric system. Symbols commonly used in single-line diagrams are defined in IEEE 315, Graphic Symbols for Electrical and Electronic Diagrams (ANSI Y32.2)
3. What protective devices are in place at the point where the customer receives service from IPL?
4. What is the customer facility minimum and maximum load?
5. What is the minimum and maximum power that the interconnection is expected to provide to IPL?
6. Describe the customer power system grounding scheme, i.e., solidly grounded, low-impedance grounded, high-impedance grounded, ungrounded
7. What is the interconnect transformer winding configuration and rating?

## Protection of the IPL Utility System from the Customer Interconnection

The primary function of interconnect protection is to prevent IPL system islanding by detecting asychronous DR operation; in other words, determining when the generator is no longer operating in parallel with the utility system. This detection and tripping must be rapid enough to allow automatic reclosing by the utility. When the loss of parallel operation is detected, the DR must be separated from the utility system quickly enough to allow the utility feeder circuit breaker at the substation to automatically reclose. High-speed reclosing from the utility system can occur as quickly as 0.3 seconds after breaker tripping.

1. Describe the operation of the customer DR interconnection for the following situations
   a) When requested by IPL to operate in parallel with the IPL system.
   b) When a short circuit (fault) condition exists on the IPL system and the customer is in parallel operation
   c) When the IPL substation feeder circuit breaker opens and the distribution circuit is connected only to the customer DR system.

2) Describe the DR restoration procedure when the utility source is returned to service from an outage condition.

3) Provide the necessary interconnect protection settings for the following devices. Settings are to include the recommended operating level and any time delay to operate. Settings should include a statement as to the associated current transformer and potential transformer ratios.
   a) Underfrequency/overfrequency (devices 81/U, 81/O)
   b) Undervoltage/overvoltage (devices 27, 59)
   c) Overcurrent (device 50/51)
   d) Ground overcurrent (device 50G/51G)
   e) Reverse power (device 32)
   f) Directional overcurrent (device 67), Impedance (device 21) or voltage restrained overcurrent (device 51V)
   g) Negative sequence (device 46)
   h) Ground detection scheme (device 64) for ungrounded systems
   i) Other protective devices provided

4) Who is the manufacturer of the protective devices?

## Testing and Commissioning

Commissioning tests shall be performed to verify settings and functionality. The tests should be performed in accordance with the design engineer's and manufacturer's recommended procedures. IPL reserves the right to witness the field test of the interconnection and its equipment.

1. What steps are proposed to verify that the installation is complete and is operating as the designer has intended?

2. What periodic tests are recommended to verify desired operation?

3. What field test protocol is proposed for inverter/converter systems with integrated relay/controllers if the DG does not meet IEEE 929/UL1741?

END
Jwh
2/15/02